

Golder Associates Inc.

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July 25, 2008

07389628

Florida Department of Environmental Protection
2600 Blirstone Road
Tallahassee, Florida 32399-2400

Attention: Mr. A. A. Linero

**RE: RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
BIOMASS GAS AND ELECTRIC; FACILITY ID NO. 0730109**

Dear Mr. Linero:

This letter is in response to your request for additional information regarding the Air Construction Permit application submitted by Golder Associates Inc. on behalf of Biomass Gas and Electric (BG&E) on April 3, 2008.

1. Material Handling. In the application, it is indicated that the wood fuel feedstock will be processed off-site and shipped by train to the facility location. The exact composition of the wood feedstock is not provided. Will the feedstock contain understory materials such as detritus material from the floor of forest areas and leaves and small branches or will it consist solely of chipped to size wood chunks from tree trunks? Detritus materials and leaves may contain mercury from dry and wet deposition which could affect the mercury emission estimates. [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response—The feedstock will consist of woody biomass, which will be processed at a remote fuel preparation area. At this remote area, the feedstock will be sorted, screened and chipped to size. Although some leaves and small branches may inadvertently find their way into the feedstock, the focus is on producing wood chips from the woody biomass. While BG&E initially proposed a small amount of yard trimmings (no more than 30 tons per day, quarterly average) as a possible feedstock source, BG&E has decided to eliminate yard trimmings as a proposed feedstock source for the Tallahassee Renewable Energy Center. Therefore, none of the feedstocks proposed for the Tallahassee Renewable Energy Center constitute “municipal solid waste”. Fuel availability appears to be both predictable and plentiful going forward, with the only real concern involving transportation costs. BG&E is being somewhat opportunistic in their feedstock approach, meaning that they will contract for some supplies, but will also take advantage of more economic market opportunities when possible. The advantage of the gasification technique is that most biomass will react the same.

Some of the available feedstock types that are categorized as woody biomass, and that are proposed for the Tallahassee Renewable Energy Center, include the following:

- *Sander Dust;*
- *Saw Dust;*

- *Georgia Pacific Fuel;*
- *Hogged Fuel;*
- *Knots and Shives;*
- *Processed Butt Cuts and;*
- *A Fuel Crop.*

The Georgia Pacific (GP) fuel is in essence the reject material off of the round wood debarking system at the GP OSB Hosford, Florida Mill. The hogged fuel is material that comprises land clearing debris that has either been pre-processed, run through a Tub Grinder, or a Horizontal Mill at a specific private forest clearing site. Knots and shives are the unique residues from the specialty pulping operation at Florida Buckeye in Perry, Florida. The butt cuts are round wood residues that are either of oversized or undersized non-processible materials from post or pole manufacturers. Finally, the fuel crop is a vegetative biomass being considered as a potential feedstock.

Attachment 1 to this letter provides constituent analyses for the different types of woody biomass summarized above, including analyses for mercury. The Department has an interest in mercury emissions and has provided references for potential mercury emissions from combustion of biomass due to forest fires. The range that is given is 14 to 71 nanograms per gram of biomass. While the references are instructive, a comparison to potential emissions from the proposed project isn't valid for several reasons. The mercury emissions from forest fires include forest understory and volatilization of mercury in soils. In addition, the BG&E project is not combustion, but gasification of the feedstock. Nevertheless, using these mercury factors from the literature, and the proposed feedstock processing rate, an uncontrolled mercury emission estimate of 103 grams per year (0.23 lb/yr) was obtained. Finally, even as these uncontrolled levels are very low in the biomass feedstock to the gasifier, the mercury that might be present is effectively further controlled in the project's proposed gas cleanup system. More detail on this system is provided in the response to Comment No. 6 in this letter.

2. Startups/Shutdowns. In the application, it is estimated that there will be a total of 6 startups of the gasifier system per year. There is no request of provisions in the permit for additional startups for shakedown during the initial operation of the facility. Does BG&E actually anticipate that the facility will not require additional startups and shutdowns of the gasifier system during the first year of the facility's operation? [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response-- During initial operations, there will be a larger number of startups and shutdowns than the 6 anticipated after the startup and shakedown period. The 6 is based on annual operations after the shakedown period.

In addition, there is a major difference between a cold startup, which takes at least 18 hours, and a hot startup, which can take from as little as a few minutes to several hours. For definition purposes, hot startups are defined as ones where the gasifier is over 1,000⁰F when the startup occurs.

At another gasification facility, the Burlington facility, there were approximately 22 cold startups/shutdowns during the first year of operation. By 2001, this number had dropped to 7. Cold startups involve a transition period during the change from air-fired operation to pyrolysis, where smoke can be produced during the change from excess oxygen combustion to sub-stoichiometric oxygen combustion, and finally to pyrolysis. This period of operation at the flare has an expected initial duration of up to 30 minutes for cold startups. One of the operational objectives of the Tallahassee plant is to reduce the length of the cold startup transition to a minimum, with a target of 10 minutes achieved after the first year of operation. Flare design to help minimize sub-stoichiometric conditions

during burnoff are a part of the preliminary engineering design effort, with the objective of minimizing smoke production during the sub-stoichiometric transition.

Emissions from hot startups are minimal, since the wood still pyrolyzes at temperature, with low tar formation. During an electrical trip, gas production tapers off over about three minutes to a zero flow. The gas is flared during this period. Since the gas varies in composition rapidly during this three minute period, there will be events of a few seconds duration where the flared gas may transition through a substoichiometric range and produce smoke.

Therefore, in response to the Department's comment, BG&E would like to clarify that as many as 22 startup/shutdowns (either hot or cold starts) could occur during the initial 12 months of operation. Subsequent to this initial decommissioning period, BG&E expects that no more than an average of 6 startup/shutdowns would be required annually.

3. Volatile Organic Compounds (VOC) and Sulfur Dioxide (SO₂) Emissions during Shutdowns.

On pages 12 to 15 of the application, emission estimates are provided for nitrogen oxides (NO_x) and particulate matter (PM) during shutdowns, while none are given for VOC and SO_x based on the argument that these emissions from the turbines are already low. What are the anticipated emissions of these pollutants during shutdowns? [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response-- As previously stated, emissions during shutdown are anticipated to be low. Emission estimates were provided for NO_x (0.075 tons per year or TPY) and PM (0.003 TPY) based on a material balance approach, engineering judgment and AP-42 emission factors. These estimates represented the total of annual planned shutdowns (about 6 per year) and emergency shutdowns (about 4 per year). Attachment 2 provides a tabular summary of all anticipated shutdown emissions, including estimates for VOC, CO and SO₂. These estimates are thought to be conservative and also rely on a material balance approach and AP-42 emission factors.

It should be noted that potential annual emissions for the project were estimated based on continuous operation (i.e., 8,760 hours per year). Therefore, in order for startup and shutdown emissions to occur, the unit would essentially be non-operational for periods of time. Any downtime of the unit would result in lower than estimated annual emissions, in spite of the fact that some emissions will occur during startup and shutdown conditions.

4. Startup and Shutdown Procedures. In Section 2.2.1 of the application, the startup and shutdown modes and procedures for the gasifier/power block are briefly described with the caveat that full descriptions of the procedures are not provided due to their proprietary nature. To effectively assess the proposed durations and associated emissions involved during the startup and shutdown of the gasifier/power block of the facility, the Department requires a full description of the procedures. Please indicate which submitted documents are considered proprietary. [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response-- The full description of the startup/shutdown procedure, which SilvaGas has currently developed, was included in the air application. SilvaGas has also developed a preliminary gasifier startup schedule (see Attachment 3, Figure 1), consistent with the cold startup duration described in the response to Comment No. 2 above. The figure presents a sequence of 16 discrete steps that comprise a typical cold startup (the worst case emissions impact). As part of Attachment 3, BG&E has provided additional detail on anticipated emissions due to startup operations (see Tables Attachment 3-1 through 3-6). The emission estimates do not rely on actual emission test data, but are based on worst-case

assumptions. Actual emissions test data during unit startups does not typically exist for many types of process operations. This is primarily because this mode of operation is typically of short duration, as well as the fact that certain required conditions (e.g., minimum threshold exhaust temperatures and flows) are necessary to conduct U.S. EPA reference method tests.

A more detailed procedure is undergoing development, to be provided to plant staff as the system Operating Manual. These procedures and associated manual are evolving as part of the detailed design phase of the engineering effort. It is not BG&E's intent to claim these procedures as proprietary. In fact, BG&E would be receptive to a permit condition that required appropriate staff training to minimize emissions during startup and shutdown events, per the procedures developed by BG&E.

5. Refractory Life. If the facility only requires 6 startups per year what is the anticipated life of the gasifier refractory? If additional startups are required, especially during the initial operation of the facility, how is the life of the refractory affected? [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response-- The refractory life varies substantially, depending on the location of the refractory in the vessel. SilvaGas obtained a patent on installing tees instead of elbows at 90 degree flow direction changes, in order to reduce the erosion rate at the ells (i.e., the critical point of circulation between the gasifier and the combustor). Improved materials suggest that the life of the refractory in straight sections of the vessels and ductwork will be approximately 5 years, although there are examples in similar services where the refractory has lasted in excess of 30 years. The worst case found at Burlington was for a vent pipe off of a seal pot, which had a gas velocity of 400 feet per second. This refractory lasted only two weeks, but was an isolated case compounded by design error.

Our cyclone vendors suggest an upper limit on gas flow velocity to minimize refractory wear in the cyclone impact zones. Hard facing of exotic materials such as silicon or tungsten carbide plates are planned for the worst impact zones. SilvaGas has used advanced computational fluid dynamics software, which can predict erosion locations and wear rates, and has incorporated the results into the project design. One of the ongoing maintenance programs for the Tallahassee plant is to verify and calibrate the computer prediction of refractory erosion locations and wear rates.

Startups and shutdown affect refractory life only if the heatup and cooldown rates result in thermal expansion-based stresses. The maximum heatup and cooldown rates for the Tallahassee plant are based on Burlington rates which successfully prevented thermal stress induced cracks. An additional factor is the refractory anchoring spacing and design. BG&E is working closely with our original refractory vendor, based out of Tampa, to provide the correct anchor spacing and design.

6. Syngas Cleanup. In Section 2.1.3 of the application, the syngas cleanup system proposed for the project is discussed. However, very few details of the proposed system are given. In previous meetings between the Department and BG&E, it was indicated by BG&E that the syngas cleanup system will be provided by Dahlman Filter Technology. Based on research done by the Department, the technology provided by Dahlman principally involves the removal of tar compounds from the syngas stream utilizing an oil wash. Details on the removal of other pollutants of concern (particulates, inorganic impurities such as sulfur compounds and volatile metals) were not available from research or in the application. Please provide to the Department a more detailed description of the syngas cleanup system proposed for the facility, including, if available, process schematics, which will allow the Department to make a comprehensive technical evaluation of the gas cleanup

system. If such information is deemed proprietary, please indicate on the submitted documents.
[Rule 62-4.070, F.A.C. Reasonable Assurance]

Response—A Technical Information Paper on Dahlman's gas cleanup technology, modified to reflect the proposed Tallahassee Renewable Energy center project, has been included as Attachment 4 to this letter. The paper provides a simplified process flow diagram of the product gas cleanup system. As described in the attachment, the gas cleanup system has no direct emissions to the atmosphere. Only condensate water leaves the closed system.

Further background on the gasifier is necessary in order to understand the operation of the gas cleanup system. The gasifier operates as a pyrolysis unit, under reducing conditions. For instance, organic sulfur and nitrogen in the feedstock are converted to H₂S and NH₃ in small amounts. In a similar fashion, it is expected that mercuric salts, methyl mercury organics or mercuric oxides would be reduced to elemental mercury, and be evaporated into the product gas. The wash oil scrubbers remove tars above the dew point of water, so the vapor pressure of the elemental mercury remains high, and at its very low concentration, is anticipated to remain in the vapor phase. The same is true of the H₂S and NH₃.

When the de-tarred product gas goes through the water scrubber at the tail end of gas cleanup, the acid gases and inorganic salts (metallic ions) are cooled down and absorbed to about a 90 percent removal level by the water. The removal level in such a system of mercury is quite low, due to the insolubility of mercury in the water, but the elemental mercury will react with the H₂S present to form mercuric sulfide, and be removed as a particulate in the main recirculating water loop. There is an additional separate section in the water scrubber that has an isolated recirculating loop of caustic soda solution. The primary objective of this section is to remove the remaining H₂S by reaction with the caustic, making sodium sulfide.

This recirculating loop of caustic soda solution with sulfides in it also provides an ideal solution for scrubbing mercuric compounds out of the vapor phase, with the dissociation constant for mercuric sulfide at 10⁻³⁵. Thus, the remaining mercury should be removed here, since the S²⁻ ion concentration will be much higher here than in the main recirculating water loop.

This is the approach used at the mercury cell caustic chlorine plants for removing any traces (i.e., ppt) of mercury from plant waste water and the food-grade product caustic soda. The water is treated with a ppm concentration or lower of S²⁻ ions, and the precipitated mercuric sulfide filtered out. Residual concentrations of mercury in the food grade caustic soda are removed in the same manner, down to non-detectable limits.

The recirculating water at the water scrubber is blown down on a regular basis, where it is used in the cooling tower as part of the cooling tower makeup water. The design has not proceeded far enough yet to determine if this water needs filtration. Should detectable mercury concentrations be obtained in either this blowdown or the blowdown from the separate caustic circulating loop, then this could be filtered to remove the mercuric sulfide particulate.

Further, the combustor receives char and olivine from the gasifier at about 1,350 °F. At this temperature, and under the gasifier reducing conditions, mercury compounds would be separated out in the upstream cyclones as part of the product gas, described above. A negligible amount of mercury would enter the combustor, as there would be virtually no mercury present in the char. However, if any mercury was present, it would likely remain in the ash bound as a non-volatile inorganic salt rather

than be released as a vapor. The vast majority of any mercury in the feedstock should end up in the makeup water from the water scrubber going to the cooling tower, and in particular, the blowdown from the separate caustic loop in the water scrubber which contains S ions.

7. Volatile Metal Emissions. As indicated in No. 6 above, no details are provided on how volatile metals, such as mercury, are going to be removed from the syngas. In the application, it is stated that the mercury concentration in the wood fuel is minimal and consequently expected mercury emissions are negligible. However, if this is not the case, does the syngas cleanup system utilize an activated carbon bed or something similar to control volatile metal emissions such as mercury? [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response—This comment is addressed above.

8. Duct Burner Firing. Based on the application, it appears that the duct burners will only fire syngas (product gas). Will natural gas ever be fired in the duct burners? [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response—Only product gas will be fired in the duct burners.

9. Emissions Averaging. In Table 3-2 of the application, emissions in ppm at 15 percent oxygen (O₂) of NO_x, carbon monoxide (CO), volatile organic compounds (VOC), and ammonia (NH₃) appear to be given for annual stack testing requirements. Please provide Continuous Emissions Monitoring System (CEMS) 24 hour block average and 12 month rolling average estimates of CO emissions and 24 hour block average and 30 day rolling average estimates of NO_x, emissions when firing the combustion turbine and the combustion turbine in combination with the duct burners for the temperatures and loads cited in the table. [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response-- BG&E's requested emission limits, as well as associated averaging times and compliance methods, are provided in Attachment 5.

10. SO₂ Emissions. On page 19 of the application, it is stated that SO₂ emissions will be minimized through the utilization of natural gas during startups and the gas cleanup system on the product gas. Please provide estimates of the SO₂ concentration in the product gas before and after cleanup. In addition, provide estimates of SO₂ stack emissions when firing product gas for the same conditions described in No. 9 above. [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response—As stated earlier, the gasifier operates as a pyrolysis unit, under reducing conditions, converting organic sulfur in the feedstock to small amounts of H₂S. The H₂S is then reduced in the gas cleanup system. SO₂ emissions would result from the residual level of H₂S in the product gas (after the gas cleanup system), which is fired in the combustion turbines and duct burners, or, in the event of a system malfunction, when the product gas is flared. Attachment 6 provides an H₂S estimate in the post-gas cleanup scenario, as well as the resultant amount of SO₂ that is estimated to be emitted by firing of the product gas in the CT/DB. SO₂ emissions from the pre-gas cleanup scenario were addressed in Attachment 3 (i.e., flare emissions during startups).

11. Combustion Turbine and Duct Burner Emissions Estimates. When comparing the upper and lower portions of Table 3-2 of the application, the emissions of NO_x, CO, and VOC appear to be lower when firing the duct burners than when not, please clarify. In addition, pollutants and units given in


the table are not defined nor is the basis for the different emission concentrations for the various pollutants. Please redo this table and resubmit to address these issues and generally provide a clear overview of the expected emissions for the project as a function of turbine load, ambient air temperature, and duct burner firing. [Rule 62-4.070, F.A.C. Reasonable Assurance]

Response— A subsequent discussion between Golder and David Read of the Department has cleared up the confusion associated with the emission table. At times, emissions on a concentration basis (i.e., ppmvd) can be lower from combined firing of a combustion turbine and duct burner than from a combustion turbine alone. Further, as stated in the response to Comment No. 9 above, BG&E has provided a tabular summary of the requested emission limits, including averaging times and methods of compliance (see Attachment 5).

Please do not hesitate to call should you require additional information.

Sincerely,

GOLDER ASSOCIATES INC.



Scott Osbourn, P.E.
Senior Consultant

Enclosures

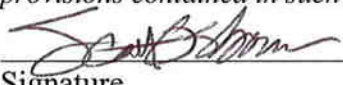
Cc: Glenn Farris, President & CEO, BG&E

SO/dcg

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APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: Scott H. Osbourn Registration Number: 57557
2. Professional Engineer Mailing Address... Organization/Firm: Golder Associates Inc.** Street Address: 5100 West Lemon Street, Suite 114 City: Tampa State: FL Zip Code: 33609
3. Professional Engineer Telephone Numbers... Telephone: (813) 287-1717 ext. 53304 Fax: (813) 287-1716
4. Professional Engineer Email Address: sosbourn@golder.com
5. Professional Engineer Statement: <i>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> (1) <i>To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and</i> (2) <i>To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.</i> (3) <i>If the purpose of this application is to obtain a Title V air operation permit (check here <input type="checkbox"/> if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.</i> (4) <i>If the purpose of this application is to obtain an air construction permit (check here <input checked="" type="checkbox"/> if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here <input type="checkbox"/> if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.</i> (5) <i>If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here <input type="checkbox"/> if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.</i> Signature: <u></u> Date: <u>7/25/08</u> (seal)


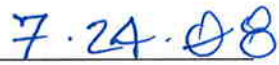


* Attach any exception to certification statement.
** Board of Professional Engineers Certificate of Authorization #00001670

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name : Glenn Farris, President & CEO
2. Owner/Authorized Representative Mailing Address... Organization/Firm: BG&E Street Address: 3500 Parkway Lane, Suite 400 City: Atlanta State: GA Zip Code: 30092
3. Owner/Authorized Representative Telephone Numbers... Telephone: (770) 662-0256 ext. Fax: (770) 662-0287
4. Owner/Authorized Representative Email Address: glenn@biggreenenergy.com
5. Owner/Authorized Representative Statement: <i>I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.</i>  _____ Signature  _____ Date

ATTACHMENT 1
FEEDSTOCK ANALYSES



April 26, 2007

BIOMASS GAS & ELECTRIC LLC
 3500 PARKWAY LANE
 SUITE 440
 NORCROSS GA 30092

Page 1 of 2

ATTN: SUE LAFLEUR

Client Sample ID:	Sander Dust	Sample ID By	Biomass Gas & Electric LLC
Date Sampled:	N/A	Sample Taken At	-----
Date Received:	Apr 5, 2007	Sample Taken By	-----
Product Description:	WOOD		

SGS Minerals Sample ID: 491-0716796-002

		<u>As Received</u>	<u>Dry</u>	<u>MAF</u>
Bromine	[ASTM D4208(MODIFIED)]		100	
% Total Moisture	[ASTM D4442(METHOD A)]	4.89		
% Ash	[ASTM D1102]	0.75	0.79	
Gross Calorific Value (Btu/lb)	[ASTM D3286]	7985	8395	8462
% Volatile Matter	[ASTM D3175]	74.94	78.79	
% Fixed Carbon	[ASTM D3172(Calc)]	19.42	20.42	
% Sulfur	[ASTM D4239(METHOD C)]	0.08	0.08	
% Carbon	[ASTM D5373]	47.66	50.10	
% Hydrogen	[ASTM D5373]	6.68	7.03	
% Nitrogen	[ASTM D5373]	4.33	4.56	
% Oxygen	[ASTM D5373(Calc)]	35.61	37.44	
Fluorine, ug/g	[ASTM D3761]		<10	
% Chlorine	[ASTM E776]	0.09	0.09	
Mercury, ug/g	[SW846-7471A]		0.09	

<u>Analyte</u>	<u>Result</u>	<u>Method</u>
Arsenic, As	<1 ug/g	ASTM D3683
Cobalt, Co	<1 ug/g	ASTM D5600
Molybdenum, Mo	<1 ug/g	ASTM D5600
Silver, Ag	<1 ug/g	ASTM D5600
Thallium, Tl	<1 ug/g	ASTM D5600
Tungsten, W	<0.50 mg/Kg	ASTM D5600
Zirconium, Zr	<0.50 mg/Kg	ASTM D5600
Sodium, Na	1020 ug/g	ASTM D5600
Potassium, K	662 ug/g	ASTM D5600
Cerium, Ce	<0.50 mg/Kg	ASTM D5600
Lithium, Li	<1 ug/g	ASTM D5600
Calcium, Ca	79 ug/g	ASTM D5600
Magnesium, Mg	252 ug/g	ASTM D5600
Barium, Ba	7 ug/g	ASTM D5600
Strontium, Sr	4 ug/g	ASTM D5600
Phosphorus, P	163 ug/g	ASTM D5600
Antimony, Sb	<1 ug/g	ASTM D5600
Chromium, Cr	<1 ug/g	ASTM D5600
Copper, Cu	<1 ug/g	ASTM D5600
Lead, Pb	<1 ug/g	ASTM D5600
Nickel, Ni	<1 ug/g	ASTM D5600



April 26, 2007

BIOMASS GAS & ELECTRIC LLC
 3500 PARKWAY LANE
 SUITE 440
 NORCROSS GA 30092

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ATTN: SUE LAFLEUR

Client Sample ID:	Saw Dust	Sample ID By	Biomass Gas & Electric LLC
Date Sampled:	N/A	Sample Taken At	-----
Date Received:	Apr 5, 2007	Sample Taken By	-----
Product Description:	WOOD		

SGS Minerals Sample ID: 491-0716796-001

		<u>As Received</u>	<u>Dry</u>	<u>MAF</u>
Bromine	[ASTM D4208(MODIFIED)]		<20	
% Total Moisture	[ASTM D4442(METHOD A)]	59.68		
% Ash	[ASTM D1102]	1.26	3.12	
Gross Calorific Value (Btu/lb)	[ASTM D3286]	3410	8458	8730
% Volatile Matter	[ASTM D3175]	31.51	78.15	
% Fixed Carbon	[ASTM D3172(Calc)]	7.55	18.73	
% Sulfur	[ASTM D4239(METHOD C)]	0.01	0.02	
% Carbon	[ASTM D5373]	20.20	50.11	
% Hydrogen	[ASTM D5373]	2.43	6.01	
% Nitrogen	[ASTM D5373]	0.11	0.26	
% Oxygen	[ASTM D5373(Calc)]	16.31	40.48	
Fluorine, ug/g	[ASTM D3761]		<10	
% Chlorine	[ASTM E776]	<0.01	0.02	
Mercury, ug/g	[SW846-7471A]		<0.02	

<u>Analyte</u>	<u>Result</u>	<u>Method</u>
Arsenic, As	<1 ug/g	ASTM D3683
Cobalt, Co	<1 ug/g	ASTM D5600
Molybdenum, Mo	<1 ug/g	ASTM D5600
Silver, Ag	<1 ug/g	ASTM D5600
Thallium, Tl	1 ug/g	ASTM D5600
Tungsten, W	<0.50 mg/Kg	ASTM D5600
Zirconium, Zr	<0.50 mg/Kg	ASTM D5600
Sodium, Na	77 ug/g	ASTM D5600
Potassium, K	338 ug/g	ASTM D5600
Cerium, Ce	1.30 mg/Kg	ASTM D5600
Lithium, Li	<1 ug/g	ASTM D5600
Calcium, Ca	178 ug/g	ASTM D5600
Magnesium, Mg	179 ug/g	ASTM D5600
Barium, Ba	8 ug/g	ASTM D5600
Strontium, Sr	6 ug/g	ASTM D5600
Phosphorus, P	73 ug/g	ASTM D5600
Antimony, Sb	<1 ug/g	ASTM D5600
Chromium, Cr	<1 ug/g	ASTM D5600
Copper, Cu	3 ug/g	ASTM D5600
Lead, Pb	<1 ug/g	ASTM D5600
Nickel, Ni	<1 ug/g	ASTM D5600



April 26, 2007

BIOMASS GAS & ELECTRIC LLC
 3500 PARKWAY LANE
 SUITE 440
 NORCROSS GA 30092

Page 1 of 2

ATTN: SUE LAFLEUR

Client Sample ID:	GP Fuel	Sample ID By	Biomass Gas & Electric LLC
Date Sampled:	N/A	Sample Taken At	-----
Date Received:	Apr 5, 2007	Sample Taken By	-----
Product Description:	WOOD		

SGS Minerals Sample ID: 491-0716796-005

		<u>As Received</u>	<u>Dry</u>	<u>MAF</u>
Bromine	[ASTM D4208(MODIFIED)]		<20	
% Total Moisture	[ASTM D4442(METHOD A)]	36.14		
% Ash	[ASTM D1102]	1.15	1.80	
Gross Calorific Value (Btu/lb)	[ASTM D3286]	5786	9061	9228
% Volatile Matter	[ASTM D3175]	47.99	75.15	
% Fixed Carbon	[ASTM D3172(Calc)]	14.72	23.05	
% Sulfur	[ASTM D4239(METHOD C)]	0.04	0.06	
% Carbon	[ASTM D5373]	35.37	55.38	
% Hydrogen	[ASTM D5373]	4.16	6.51	
% Nitrogen	[ASTM D5373]	0.17	0.27	
% Oxygen	[ASTM D5373(Calc)]	22.97	35.98	
Fluorine, ug/g	[ASTM D3761]		<10	
% Chlorine	[ASTM E776]	0.01	0.02	
Mercury, ug/g	[SW846-7471A]		<0.02	

<u>Analyte</u>	<u>Result</u>	<u>Method</u>
Arsenic, As	5 ug/g	ASTM D3683
Cobalt, Co	<1 ug/g	ASTM D5600
Molybdenum, Mo	<1 ug/g	ASTM D5600
Silver, Ag	<1 ug/g	ASTM D5600
Thallium, Tl	<1 ug/g	ASTM D5600
Tungsten, W	<0.50 mg/Kg	ASTM D5600
Zirconium, Zr	<0.50 mg/Kg	ASTM D5600
Sodium, Na	368 ug/g	ASTM D5600
Potassium, K	733 ug/g	ASTM D5600
Cerium, Ce	<0.50 mg/Kg	ASTM D5600
Lithium, Li	<1 ug/g	ASTM D5600
Calcium, Ca	193 ug/g	ASTM D5600
Magnesium, Mg	477 ug/g	ASTM D5600
Barium, Ba	7 ug/g	ASTM D5600
Strontium, Sr	6 ug/g	ASTM D5600
Phosphorus, P	251 ug/g	ASTM D5600
Antimony, Sb	<1 ug/g	ASTM D5600
Chromium, Cr	<1 ug/g	ASTM D5600
Copper, Cu	3 ug/g	ASTM D5600
Lead, Pb	<1 ug/g	ASTM D5600
Nickel, Ni	<1 ug/g	ASTM D5600



April 26, 2007

BIOMASS GAS & ELECTRIC LLC
 3500 PARKWAY LANE
 SUITE 440
 NORCROSS GA 30092

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ATTN: SUE LAFLEUR

Client Sample ID:	Hogged Fuel	Sample ID By	Biomass Gas & Electric LLC
Date Sampled:	N/A	Sample Taken At	-----
Date Received:	Apr 5, 2007	Sample Taken By	-----
Product Description:	WOOD		

SGS Minerals Sample ID: 491-0716796-004

		<u>As Received</u>	<u>Dry</u>	<u>MAF</u>
Bromine	[ASTM D4208(MODIFIED)]		<20	
% Total Moisture	[ASTM D4442(METHOD A)]	34.54		
% Ash	[ASTM D1102]	1.10	1.67	
Gross Calorific Value (Btu/lb)	[ASTM D3286]	5403	8254	8394
% Volatile Matter	[ASTM D3175]	51.96	79.37	
% Fixed Carbon	[ASTM D3172(Calc)]	12.40	18.96	
% Sulfur	[ASTM D4239(METHOD C)]	0.02	0.03	
% Carbon	[ASTM D5373]	30.89	47.20	
% Hydrogen	[ASTM D5373]	3.64	5.56	
% Nitrogen	[ASTM D5373]	0.22	0.34	
% Oxygen	[ASTM D5373(Calc)]	29.59	45.20	
Fluorine, ug/g	[ASTM D3761]		<10	
% Chlorine	[ASTM E776]	0.02	0.02	
Chlorine, ug/g	[SW846-7471A]		0.03	

<u>Analyte</u>	<u>Result</u>	<u>Method</u>
Arsenic, As	4 ug/g	ASTM D3683
Cobalt, Co	<1 ug/g	ASTM D5600
Molybdenum, Mo	<1 ug/g	ASTM D5600
Silver, Ag	<1 ug/g	ASTM D5600
Thallium, Tl	3 ug/g	ASTM D5600
Tungsten, W	<0.50 mg/Kg	ASTM D5600
Zirconium, Zr	0.69 mg/Kg	ASTM D5600
Sodium, Na	89 ug/g	ASTM D5600
Potassium, K	1146 ug/g	ASTM D5600
Cerium, Ce	<0.50 mg/Kg	ASTM D5600
Lithium, Li	<1 ug/g	ASTM D5600
Calcium, Ca	212 ug/g	ASTM D5600
Magnesium, Mg	411 ug/g	ASTM D5600
Barium, Ba	8 ug/g	ASTM D5600
Strontium, Sr	5 ug/g	ASTM D5600
Phosphorus, P	466 ug/g	ASTM D5600
Antimony, Sb	<1 ug/g	ASTM D5600
Chromium, Cr	<1 ug/g	ASTM D5600
Copper, Cu	3 ug/g	ASTM D5600
Lead, Pb	2 ug/g	ASTM D5600
Nickel, Ni	<1 ug/g	ASTM D5600



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 NORCROSS GA 30092

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ATTN: SUE LAFLEUR

Client Sample ID:	Knots & Shives	Sample ID By	Biomass Gas & Electric LLC
Date Sampled:	N/A	Sample Taken At	-----
Date Received:	Apr 5, 2007	Sample Taken By	-----
Product Description:	WOOD		

SGS Minerals Sample ID: 491-0716796-007

		<u>As Received</u>	<u>Dry</u>	<u>MAF</u>
Bromine	[ASTM D4208(MODIFIED)]		29	
% Total Moisture	[ASTM D4442(METHOD A)]	61.59		
% Ash	[ASTM D1102]	3.26	8.48	
Gross Calorific Value (Btu/lb)	[ASTM D3286]	2940	7655	8364
% Volatile Matter	[ASTM D3175]	28.31	73.71	
% Fixed Carbon	[ASTM D3172(Calc)]	6.84	17.81	
% Sulfur	[ASTM D4239(METHOD C)]	0.14	0.36	
% Carbon	[ASTM D5373]	17.76	46.25	
% Hydrogen	[ASTM D5373]	2.20	5.74	
% Nitrogen	[ASTM D5373]	0.04	0.11	
% Oxygen	[ASTM D5373(Calc)]	15.01	39.06	
Fluorine, ug/g	[ASTM D3761]		<10	
% Chlorine	[ASTM E776]	0.03	0.09	
Mercury, ug/g	[SW846-7471A]		<0.02	

<u>Analyte</u>	<u>Result</u>	<u>Method</u>
Arsenic, As	<1 ug/g	ASTM D3683
Cobalt, Co	<1 ug/g	ASTM D5600
Molybdenum, Mo	<1 ug/g	ASTM D5600
Silver, Ag	<1 ug/g	ASTM D5600
Thallium, Tl	2 ug/g	ASTM D5600
Tungsten, W	<0.50 mg/Kg	ASTM D5600
Zirconium, Zr	<0.50 mg/Kg	ASTM D5600
Sodium, Na	640 ug/g	ASTM D5600
Potassium, K	52 ug/g	ASTM D5600
Cerium, Ce	<0.50 mg/Kg	ASTM D5600
Lithium, Li	<1 ug/g	ASTM D5600
Calcium, Ca	107 ug/g	ASTM D5600
Magnesium, Mg	318 ug/g	ASTM D5600
Barium, Ba	<1 ug/g	ASTM D5600
Strontium, Sr	2 ug/g	ASTM D5600
Phosphorus, P	10 ug/g	ASTM D5600
Antimony, Sb	<1 ug/g	ASTM D5600
Chromium, Cr	<1 ug/g	ASTM D5600
Copper, Cu	<1 ug/g	ASTM D5600
Lead, Pb	1 ug/g	ASTM D5600
Nickel, Ni	<1 ug/g	ASTM D5600



April 26, 2007

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SUITE 440
NORCROSS GA 30092

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ATTN: SUE LAFLEUR

Client Sample ID:	Processed Butt Cuts	Sample ID By	Biomass Gas & Electric LLC
Date Sampled:	N/A	Sample Taken At	-----
Date Received:	Apr 5, 2007	Sample Taken By	-----
Product Description:	WOOD		

SGS Minerals Sample ID: 491-0716796-006

		<u>As Received</u>	<u>Dry</u>	<u>MAF</u>
Bromine	[ASTM D4208(MODIFIED)]		<20	
% Total Moisture	[ASTM D4442(METHOD A)]	31.52		
% Ash	[ASTM D1102]	0.33	0.48	
Gross Calorific Value (Btu/lb)	[ASTM D3286]	5708	8336	8376
% Volatile Matter	[ASTM D3175]	57.01	83.25	
% Fixed Carbon	[ASTM D3172(Calc)]	11.14	16.27	
% Sulfur	[ASTM D4239(METHOD C)]	0.01	0.01	
% Carbon	[ASTM D5373]	35.37	51.65	
% Hydrogen	[ASTM D5373]	4.18	6.10	
% Nitrogen	[ASTM D5373]	0.13	0.19	
% Oxygen	[ASTM D5373(Calc)]	28.46	41.57	
Fluorine, ug/g	[ASTM D3761]		<10	
% Chlorine	[ASTM E776]	0.02	0.03	
Mercury, ug/g	[SW846-7471A]		<0.02	

<u>Analyte</u>	<u>Result</u>	<u>Method</u>
Arsenic, As	<1 ug/g	ASTM D3683
Cobalt, Co	<1 ug/g	ASTM D5600
Molybdenum, Mo	<1 ug/g	ASTM D5600
Silver, Ag	<1 ug/g	ASTM D5600
Thallium, Tl	<1 ug/g	ASTM D5600
Tungsten, W	<0.50 mg/Kg	ASTM D5600
Zirconium, Zr	<0.50 mg/Kg	ASTM D5600
Sodium, Na	26 ug/g	ASTM D5600
Potassium, K	126 ug/g	ASTM D5600
Cerium, Ce	<0.50 mg/Kg	ASTM D5600
Lithium, Li	<1 ug/g	ASTM D5600
Calcium, Ca	41 ug/g	ASTM D5600
Magnesium, Mg	117 ug/g	ASTM D5600
Barium, Ba	2 ug/g	ASTM D5600
Strontium, Sr	2 ug/g	ASTM D5600
Phosphorus, P	22 ug/g	ASTM D5600
Antimony, Sb	<1 ug/g	ASTM D5600
Chromium, Cr	<1 ug/g	ASTM D5600
Copper, Cu	<1 ug/g	ASTM D5600
Lead, Pb	<1 ug/g	ASTM D5600
Nickel, Ni	<1 ug/g	ASTM D5600

AS-RECEIVED BIOMASS FUEL CROP ANALYSIS

		mang	P'cola	SC	generic	near	site	Avg	Range	standard
		lab 1	(unmang)	(unmang)	ocean	lab 3	expected			deviation
Dry Analysis										
Ash	% wt	2.61	3.80	3.16	3.43	3.80	3.25	1.19	0.43	
Carbon	% wt	47.39	47.42	47.60	47.06	47.42	47.37	0.54	0.19	
Fixed Carbon	% wt	9.79	20.34	22.97	16.38	20.34	17.37	13.18	4.96	
Hydrogen	% wt	5.51	5.73	5.85	5.84	5.73	5.73	0.34	0.14	
Nitrogen	% wt	0.88	0.44	0.47	0.60	0.44	0.60	0.44	0.17	
Oxygen	% wt	43.45	42.50	42.71	42.95	42.50	42.90	0.95	0.35	
Volatiles	% wt	87.60	75.75	73.66	80.19	75.75	79.30	13.94	5.34	
Sulfur	% wt	0.16	0.11	0.21	0.12	0.11	0.15	0.10	0.04	
Chlorine	% wt		0.00	0.00	0.20	0.00	0.07	0.20	0.09	
Heat of Comb, LHV	Btu/lb	8,180	8,070	8,100	8,104	8,070	8,114	110	40.58	
lb / MMBtu		122.2	123.9	123.5	123.4	123.9	123.3			

Normal Moisture, As Received Analysis

Moisture	% wt	40.00	39.42	31.47	42.01	23.35	38.23	10.54	4.02	
Ash	% wt	1.57	2.30	2.17	1.99	2.91	2.01	0.74	0.28	
Carbon	% wt	28.43	28.73	32.62	27.29	36.35	29.27	5.33	2.01	
Fixed Carbon	% wt	5.87	12.32	15.74	9.50	15.59	10.86	9.87	3.63	
Hydrogen	% wt	3.31	3.47	4.01	3.39	4.39	3.54	0.70	0.28	
Nitrogen	% wt	0.53	0.27	0.32	0.35	0.34	0.37	0.26	0.10	
Oxygen	% wt	26.07	25.75	29.27	24.91	32.58	26.50	4.36	1.66	
Volatiles	% wt	52.56	45.89	50.48	46.50	58.06	48.86	6.67	2.77	
Sulfur	% wt	0.10	0.07	0.14	0.07	0.08	0.09	0.08	0.03	
Heat of Comb, LHV	Btu/lb	4,908	4,889	5,551	4,700	6,186	5,012	851	321.75	
lb / MMBtu		203.7	204.5	180.1	212.8	161.7	199.5			

Major/Minor Oxides in Ash

Aluminum Oxide	% wt	0.70	0.11	0.11	0.80	0.10	0.43	0.69	0.32	
Calcium Oxide	% wt	5.27	9.42	6.20	2.78	8.23	5.92	6.64	2.38	
Iron Oxide	% wt	0.29	0.63	0.52	0.86	0.55	0.58	0.57	0.21	
Magnesium Oxide	% wt	3.75	7.69	6.32	3.07	6.72	5.21	4.62	1.88	
Phos. Pentoxide	% wt	5.43	7.30	5.11	6.16	6.38	6.00	2.19	0.84	
Potassium Oxide	% wt	30.43	21.47	29.85	30.00	18.76	27.94	8.96	3.74	
Silicon Dioxide	% wt	22.81	32.39	29.80	44.21	45.00	32.30	21.40	7.72	
Sodium Oxide	% wt	1.50	4.14	2.12	0.49	3.62	2.06	3.65	1.33	
Sulfur Trioxide	% wt	4.47	4.90	8.63	4.82	4.28	5.71	4.16	1.70	
Titanium Oxide	% wt	0.03	0.01	0.01	0.10	0.01	0.04	0.09	0.04	
Undetermined		25.32	11.94	11.33	6.71	10.43	13.83	18.61	6.94	
Alkali, Lb/MMBtu		1.31	1.91	1.69	1.68	1.67	1.65	0.60	0.22	
Percent S in Ash		39%	90%	69%	73%	79%	68%	0.51	0.19	

Ash Fusion

CaO (lb/MMBtu, dry)	0.17	0.44	0.24	0.12	0.39	0.24			
K2O (lb/MMBtu, dry)	0.97	1.01	1.16	1.27	0.88	1.12			
SiO2 (lb/MMBtu, dry)	0.73	1.53	1.16	1.87	2.12	1.29			
Ternary CaO	9%	15%	9%	4%	11%	9%			
Ternary K2O	52%	34%	45%	39%	26%	42%			
Ternary SiO2	39%	51%	45%	57%	63%	49%			

ASPEN Inputs

C (moles / 10-lb dry)	39.46	39.48	39.63	39.18	39.48	39.44			
H2 (moles / 10-lb dry)	27.33	28.43	29.02	28.97	28.43	28.44			
N2 (moles / 10-lb dry)	0.31	0.16	0.17	0.21	0.16	0.21			
O2 (moles / 10-lb dry)	13.58	13.28	13.35	13.42	13.28	13.41			
C6H10O5 (moles / 10 lb)	6.58	6.58	6.61	6.53	6.58	6.57			
H2 excess of C6H10O5	21.85	22.94	23.52	23.53	22.94	22.96			
O2 excess of C6H10O5	10.84	10.54	10.60	10.70	10.54	10.67			

ATTACHMENT 2
SHUTDOWN EMISSIONS SUMMARY

Table Attachment 2-1. Shutdown Emissions Summary

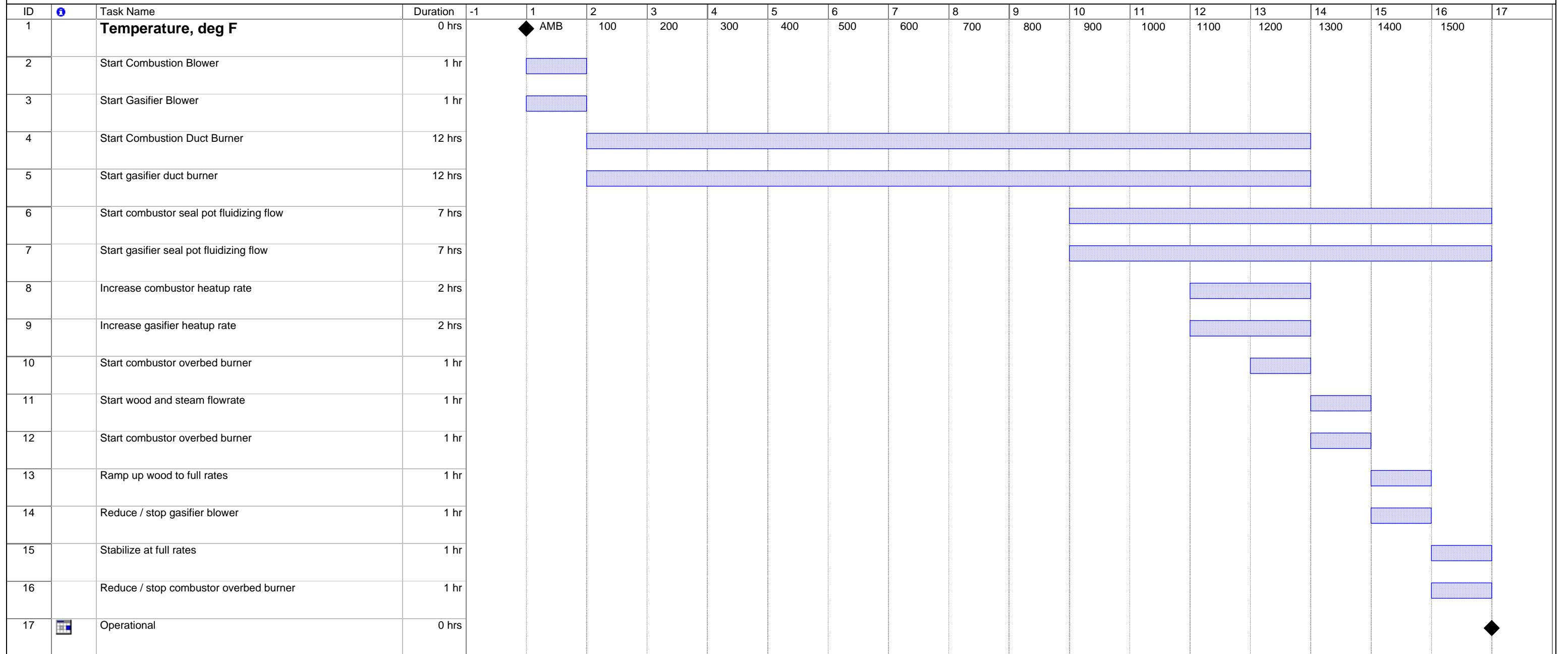
Emission Component	Pollutant *	Planned ** Shutdowns, TPY	Emergency ** Shutdowns, TPY	Total Annual Emissions (TPY)
Gasifier Island/Flare	NOX	0.0500	0.0250	0.075
	PM/PM10	0.0025	0.0005	0.003
	CO	0.0011	0.0008	0.002
	VOC	0.0003	0.0002	0.001
	SO2	0.0090	0.0060	0.015

* Based upon information from SilvaGas and AP-42 Section 1.1 for Cyclone Furnace, Bituminous

** Based on an estimated 6 planned shutdowns/yr and an estimated 4 emergency shutdowns/yr

ATTACHMENT 3
STARTUP SCHEDULE AND EMISSIONS

Preliminary Gasifier Start-Up Schedule



Project: Master BG&E Shell_r
Date: January 8, 2008

Task
Split



Progress
Milestone



Summary
Project Summary



External Tasks
External Milestone



Deadline



Table Attachment 3-1

Natural Gas Firing (CT Only)		
Sulfur Content		2 gr/100 scf
Heat Input	CT	147 MMBtu/hr
	DB	-- MMBtu/hr
	Total	147 MMBtu/hr
Heating value		1040 btu/cf
Fuel use		141,346.15 cf/hr
		1,413.46 100 cf/hr
S		0.40 lb/hr
SO2		0.81 lb/hr
Emission Factors	CO	8.2E-02 lb/MMBtu AP-42 Table 3.1-1
	VOC	2.1E-03 lb/MMBtu AP-42 Table 3.1-2a
	PMtot	6.6E-03 lb/MMBtu AP-42 Table 3.1-2a
CO		0.00 lb/hr
VOC		0.00 lb/hr
PMtot		0.00 lb/hr
NOx Conc.		25 ppm
Volumetric flowrate		142,444.90 acfm
Stack Temperature		1,074 F assumed
MW		46
NOx		8.78 lb/hr

Table Attachment 3-2. Auxiliary Boiler Emissions

Performance

Fuel Usage (scf/hr-gas)	60,713
Heat Input (mmBtu/hr-HHV)	62.00
Hours per Year	500
Maximum Fuel Usage (mmscf/yr)	30.36

Stack Parameters

Diameter (ft)	2.75
Height (ft)	50
Temperature (°F)	296
Velocity (ft/sec)	81
Flow (acfm)	29,000

Emissions

SO ₂ -Basis (grains S/100 scf-gas; %S diesel)	2.00
(lb/hr)	0.35
(tpy)	0.01
NO _x - (lb/mmBtu)	0.095
(lb/hr)	5.89
(tpy)	0.09
CO - (lb/mmBtu)	0.08
(lb/hr)	4.96
(tpy)	0.08
VOC - (lb/mmBtu)	0.005
(lb/hr)	0.31
(tpy)	0.00
PM/PM10 - (lb/10 ⁶ ft ³)	1.90
(lb/hr)	0.12
(tpy)	0.00

* Based on AP-42 Section 1.4

Table Attachment 3-3. Combustor & Gasifier Burner Emissions

Performance

Fuel Usage (scf/hr-gas)	41,176
Heat Input (mmBtu/hr-HHV)	42.00
Hours per Year	72
Maximum Fuel Usage (mmscf/yr)	2.96

Stack Parameters

Diameter (ft)	TBD
Height (ft)	TBD
Temperature (°F)	TBD
Velocity (ft/sec)	TBD
Flow (acfm)	TBD

Emissions

SO ₂ -Basis (grains S/100 scf-gas; %S diesel)	2.00
(lb/hr)	0.24
(tpy)	0.00
NO _x - (lb/mmBtu)	0.098
(lb/hr)	4.12
(tpy)	0.00
CO - (lb/mmBtu)	0.08
(lb/hr)	3.36
(tpy)	0.00
VOC - (lb/mmBtu)	0.005
(lb/hr)	0.21
(tpy)	0.00
PM/PM10 - (lb/10 ⁶ ft ³)	1.90
(lb/hr)	0.08
(tpy)	0.00

* Based on AP-42 Section 1.4

Table Attachment 3-4. Gasifier Combustor Startup Emissions

Performance

Product Gas Produced (MMBtu/hr)	376
Quantity of Residual Char (%)	33.0
Heat Input from Residual Char (MMBtu/hr)	124
Char Heating Value (Btu/lb)	14,500
Hours of Operation	72

Stack Parameters

Diameter (ft)	TBD
Height (ft)	TBD
Temperature (°F)	TBD
Velocity (ft/sec)	TBD
Flow (acfm)	TBD

Emissions

SO ₂ -Basis is feedstock organic sulfur (%)	0.004
Feedstock Rate (dry TPD)	730
(lb/hr)	0.0
(tpy)	0.01
NO _x - with tar recycle (10 hr/SU * 6 SU/yr)	60.00
(lb/hr)	9.9
(tpy)	0.0
NO _x - w/out tar recycle (12 hr/SU * 6 SU/yr)	72.00
(lb/hr)	99.9
(tpy)	0.0
CO - (lb/ton) AP-42, Table 1.2-2	0.6
Char produced (ton/hr)	4.3
(lb/hr)	2.6
(tpy)	0.1
VOC - (lb/ton) AP-42, Table 1.2-6	0.3
Char produced (ton/hr)	4.3
(lb/hr)	1.3
(tpy)	0.0
PM/PM10-(lb/ton) AP-42, Table 1.2-3	71.2
Char produced (ton/hr)	4.3
(lb/hr)	304.6
Cyclone/Baghouse Efficiency (%)	98.0
(tpy)	0.2

Table Attachment 3-5. Flare System Emissions

<u>Parameter</u>		<u>Value</u>	<u>Units</u>	<u>Source/Description</u>
Fuel Flow		19,627	lbm/hr	Gas Analysis 18-Oct -07, Solar
Energy Density		7,337	Btu/lbm	Gas Analysis 18-Oct -07, Solar, Low Heating Value of fuel
Energy Input to Flare		144	MMBtu/hr	Energy Input = Fuel Flow * Energy Density / 1,000,000
<u>Emissions</u>				
TOC -	Emission Factor	0.14	lb/MMBtu	AP-42 Table 13.5-1
	Emission Rate	-	lb/hr	Emission Rate = Emission Factor * Energy Input
	Emission Rate	-	tpy	Emission Rate (tpy) = Emission Rate (lb/hr) * 144 /2000 (144 hr/yr is assumed to be 6 SU/yr @ 24 hr/SU)
CO -	Emission Factor	0.37	lb/MMBtu	AP-42 Table 13.5-1
	Emission Rate	-	lb/hr	Emission Rate = Emission Factor * Energy Input
	Emission Rate	-	tpy	Emission Rate (tpy) = Emission Rate (lb/hr) * 144/2000
NO _x -	Emission Factor	0.068	lb/MMBtu	AP-42 Table 13.5-1
	Emission Rate	-	lb/hr	Emission Rate = Emission Factor * Energy Input
	Emission Rate	-	tpy	Emission Rate (tpy) = Emission Rate (lb/hr) * 144/2000
SO ₂ (Based on Mass Balance) -	Heating Value	435.0	Btu/scf	Heating Value of Syngas @ 14.7 psia & 60°F
	Syngas Flow	331,042.1	scf/hr	144 MMBtu * 1,000,000 / 435 btu/scf
	H2S in syngas	0.10	% by vol	Based on untreated gas H2S value of ~ 50 ppm
	H2S Flow	331.0	scf/hr	86687 scfm * 0.0002 vol %
	gas constant	0.0029	cf-atm/mol-K	Constant
	H2S Molar Flow	395.7	g-mol/hr	n= (1 atm) * (17.34 scfm) / (0.0029 cf-atm/mol-K) / (288.7K)
	MW SO ₂	64.1	g/g-mol	1 mol of H2S forms 1 mol of SO ₂
	SO ₂ Mass Flow	25,364.1	g/hr	20.7 gmol/hr * 64.1 g/gmol
	SO ₂ Mass Flow	55.9	lb/hr	5072 g/hr / 453.59 g/lb
SO ₂ Mass Flow	4.0	tpy	11.2 lb/hr * 144/ 2000	
Soot (PM) -	AP-42, Table 13.5-1--- fuels with a C:H ratio of less than 0.33 tend not to soot. The average C:H ratio in the syngas is less than 0.33.			

Table Attachment 3-6. Total Startup Emissions							
Pollutant	Emission Units					Total Emissions	
	Gasifier/Combustor Burners	Boiler	Combustor	Flare	Combustion Turbines		
NOX	0.15	1.47	3.89	0.7	0.0088	6.2	
CO	0.12	1.24	0.09	3.8	0.0121	5.3	
PM	0.00	0.03	0.22	Neg	0.0010	0.3	
SO2	0.01	0.09	0.01	4.0	0.0008	4.1	
VOC	0.01	0.08	0.05	1.5	0.0003	1.6	

ATTACHMENT 4
DAHLMAN GAS CLEANUP SYSTEM



OLGA Tar Removal

- Biomass gasification to electricity and more.. -

Revision spring 2008

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Ministry of Economic Affairs

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Note: The information below reflects proposed operation of the Tallahassee Renewable Energy Center project.

1 Gas Purification Overview

Purification of product gas is an important aspect of operation for the Tallahassee Renewable Energy Center project. The gas purification steps that are necessary and how efficient they should be are dependent upon:

- 1 Feedstock (e.g. biomass) and its chemical components
- 2 Gasification technology & operational conditions of the gasifier
- 3 The application and downstream equipment; how clean should the gas be?

In general, we can identify the following gas treatment steps, summarized in their most logical order

- Particulate removal
 - Cyclones, filters, electrostatic filters
- Removal of organic impurities
 - Tar removal is the most important: OLGA
- Removal of inorganic impurities
 - Removal of nitrogen, halogens (mainly NH_3 and HCl) and low quantities of sulfur (H_2S), by scrubber (water) technology
- Sulfur removal (H_2S) by a caustic polishing step
- Removal of volatile (alkali / heavy) metals (e.g. mercury)
 - Mercuric sulfide removed as particulate in the water scrubber; vapor phase mercuric compounds removed in a caustic polishing step.

In general, we can say that the particulates and tars are produced by the gasifier. Gasifier type and operation determine the concentration and composition. OLGA combines the particulate and tar removal and is thus always a close match with the gasifier.

2 Tar Removal From Biomass Product Gas

The presence of tars in the biomass product gas is seen as the biggest issue in its smooth commercial application as a source of sustainable energy. Tar is formed in the gasifier and comprises a wide spectrum of organic compounds, generally consisting of several aromatic rings. The tar concentration

and composition is mostly determined by gasifier type and operation. Simplified tars can be distinguished as “heavy tars” and “light tars”:

Heavy tars

Heavy tars condense out as the gas temperature drops and cause major fouling, efficiency loss and unscheduled plant stops. The tar dew point is a critical factor.



*Figure 2.1, 2.2 & 2.3. Heavy tar fouls equipment, left to right:
a water scrubber grid, soot formation on catalyst & a gas engine intercooler*

Light tars

Light tars, like phenol or naphthalene, have limited influence on the tar dew point, but are not less of an issue. Light heterocyclic tars, like phenol, are very water soluble. These tars will be easily absorbed into water and chemically affect the bleed water of downstream condensers and aqueous scrubbers. Purification of this water is very cost- intensive and will jeopardize the plant’s economic feasibility. Naphthalene is important, as it is known to crystallize at the inlet of gas engines causing a high service demand.



*Figure 2.4 & 2.5: light tar fouls equipment & seriously contaminates condense water,
Left- a gas engine control valve fouled with naphthalene crystals
Right- contaminated condense water samples*

Tar defined

A well accepted definition states that tars are all organic compounds with a molecular weight bigger than benzene. BTX (benzene, toluene and xylene) are components which are not considered to be as important, as they are not likely to influence the tar dew point nor to affect waste water treatment. A better and more detailed tar description is given by the classification of tars (see Appendix A).

The tar dew point, a critical parameter

The lowest temperature in the process is determined by downstream equipment and the application of the product gas. As typical tar dew points are between 150°C and 350 °C, and the lowest process temperature is typically 30-40 °C, tar condensation and tar issues are inevitable. It is important to realize that the actual tar concentration is not the most important parameter. It is the tar dew point which defines the point at which tars start to be a concern. One of the most important goals for the OLGA technology is to lower the tar dew point to a level at which such concerns can be excluded.

3 OLGA's Gas Cleaning Process

To introduce you to the OLGA technology, it is important to first show its position in a generic line-up of an integrated air blown gasification system with a gas engine for combined heat & power (CHP) production:

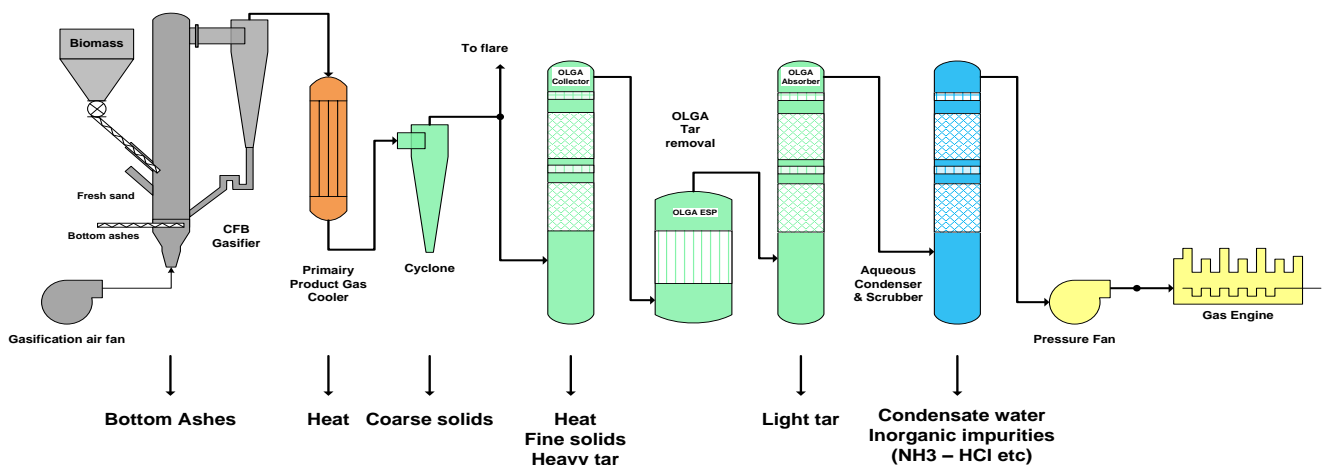


Figure 2.6 Generic line up

Product gas cleaning can be split into the following logical steps:

1. Solids/dust removal
2. Removal of organic impurities (tar)
3. Removal of inorganic impurities (e.g., NH₃, HCl, H₂S)

Product gas produced by the gasifier contains solids (dust), tars and inorganic impurities (depending on biomass feedstock). It is very important to consider the logical order for cleaning the product gas. In principle, mixing dust, tar and water is to be avoided.

Dust removal with OLGA

Solid particles (dust) can be separated from the product gas upstream OLGA by a cyclone or a hot gas filter (HGF). It is best to separate the dust first, as dust can be removed at a temperature in which water and tars are not present (>400 C). For the Tallahassee Renewable Energy Center project, it was decided to remove the coarse particles with a cyclone. The fine particles which pass this cyclone are captured by the Collector column and the ESP. A very high efficiency on particle capture can be ensured.

Removal of Organic Impurities

The philosophy of OLGA is based on dew point control. Tars have to be removed above the water dew point to a level at which the tar situation cannot occur in downstream equipment (minimal process temperature > tar dew point). In the figure below, the tar and water dew points are shown, together with the logical process steps.

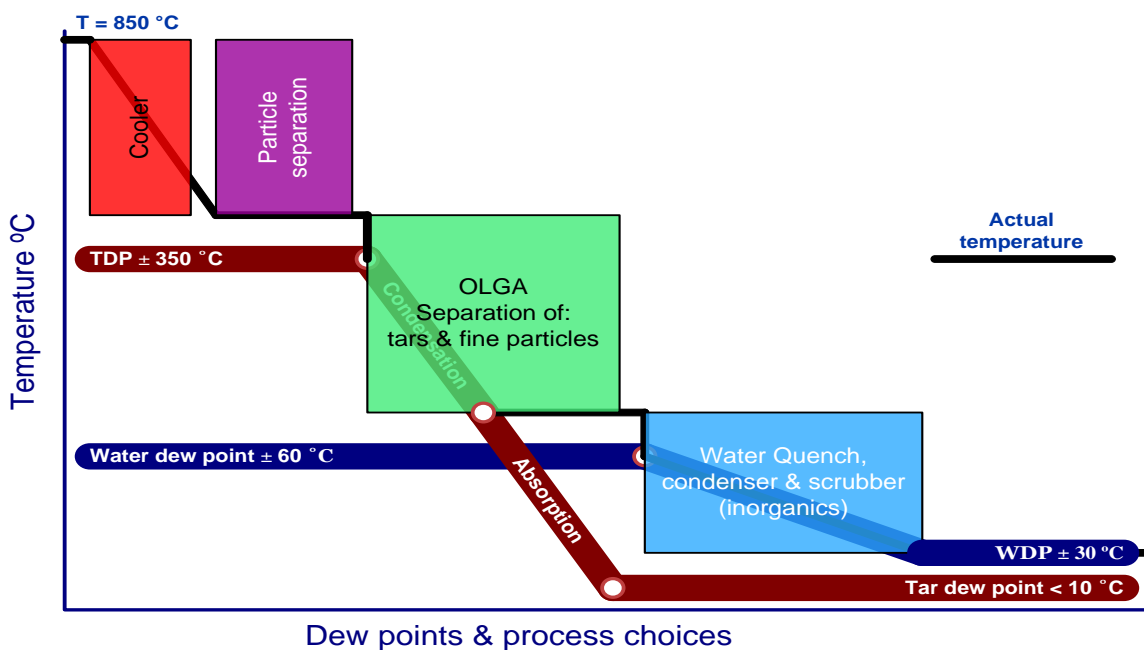


Figure 2.7 Dew points are important for equipment selection

Logical equipment with typical temperatures:

1. Product gas cooler; gasifier exit 700-900 °C– OLGA inlet 380 °C
2. Separation of solids; 380 °C
 - coarse solids by a cyclone (OLGA for fine solid aerosols)
 - all solids by a hot gas filter
3. OLGA tar separation; inlet 380 °C outlet 70-90 °C (safe above water dew point)
4. Water condenser; 70-90 °C to 30 °C
5. Water scrubber; 30 °C

OLGA operates above the water dew point, but decreases the tar dew point to a level under the lowest process temperature. Tar and water are not mixed. The tar removal principle of OLGA is based on a multiple stage scrubber in which the gas is cleaned by special scrubbing oil. In the first section of OLGA (the Collector) the gas is gently cooled down by the scrubbing oil. Heavy tar condenses, is collected, and is separated from the scrubbing oil. The heavy tar condensate, together with the fine solids, is recycled to the gasifier as a liquid. In the second stage (the Absorber / Stripper) lighter gaseous tars are absorbed by the scrubbing oil resulting in a product gas practically free from tars and solids.

In the absorber column, the scrubbing oil is saturated by these lighter tars. This saturated oil is regenerated in a stripper. Hot air is used to strip the tars of the scrubbing oil. This air, loaded with light tars, is recycled to the gasifier for combusting and as a fluidization medium. Hence, the stripper column design is not only based upon tar removal, but also upon the amount of air that can be used by the gasifier.

All heavy and light tars can be recycled to the gasifier where they are destructed and contribute to the overall energy efficiency. Tar waste streams are efficiently recycled this way.

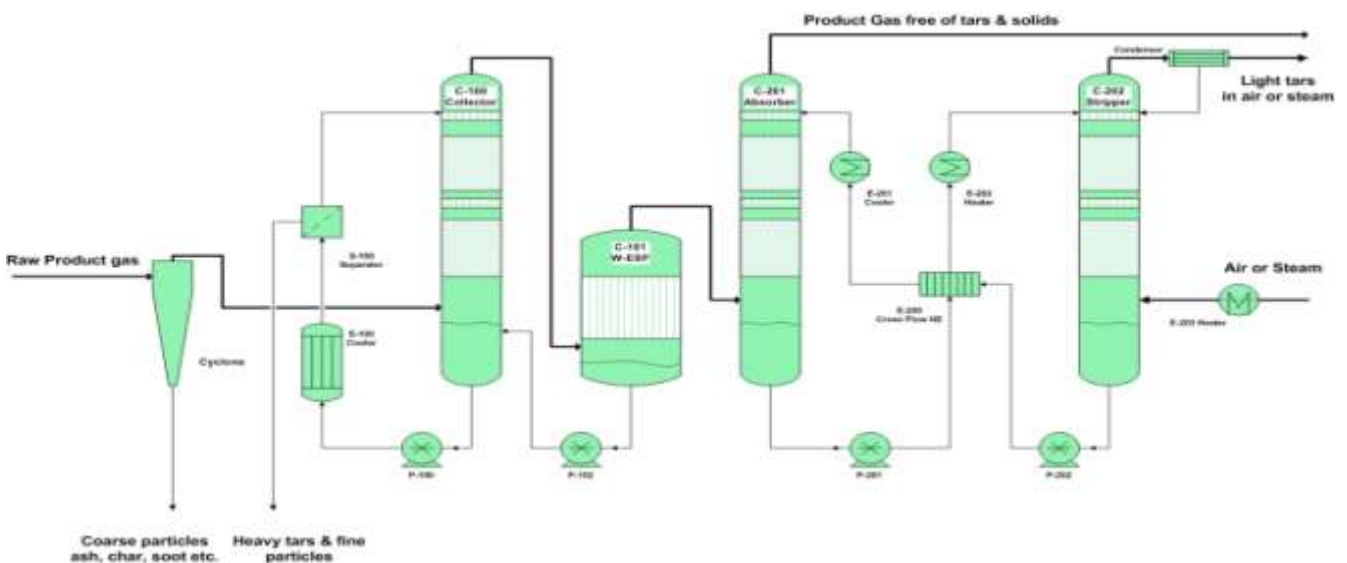


Figure 2.8 Simplified Process Flow Diagram of OLGA

Aqueous Scrubbers, Condensers and Caustic Polishing Downstream of OLGA

When gas is free of tar, an aqueous scrubber column can be operated more efficiently. This aqueous scrubber is normally used for:

1. Cooling the gas by quenching;
2. Further cooling of the gas and removal of the bulk of the water vapor by condensation;
3. Removal of water soluble components like NH_3 , HCl , H_2S , if applicable.

The inorganic scrubber system is built as one column which is split into two sections. In section one, the gas will enter the column at the bottom and is scrubbed with cooling water. A large part of the water in the gas will condense and NH_3 and HCl will dissolve in the water and be removed from the gas. Also, part of the H_2S will dissolve in the water, but not enough to meet the gas turbine specification. Therefore, the inorganic scrubber system is executed with a second section. In this section, the remaining H_2S is removed by a caustic polishing step. Diluted sodium hydroxide is the preferred caustic for this use. There is an additional separate section in the water scrubber that has an isolated recirculating loop of caustic soda solution. The primary objective of this section is to remove the remaining H_2S by reaction with the caustic, making sodium sulfide.

The following paragraphs provide more detail on the chemistry of mercury within the process and its removal from the system. When the de-tarred product gas goes through the water scrubber at the tail end of gas cleanup, the acid gases and inorganic salts (metallic ions) are cooled down and absorbed to about a 90 percent removal level by the water. The removal level in such a system of mercury is probably low, due to the insolubility of mercury in the water, but the elemental mercury reacts with the H_2S present to make mercuric sulfide, and drops out as a particulate in the main recirculating water loop. The recirculating loop of caustic soda solution with sulfides in it provides an ideal solution for scrubbing mercuric compounds out of the vapor phase, with the dissociation constant for mercuric sulfide at 10⁻³⁵. Thus, all of the remaining mercury will likely be removed here, since the S⁻ ion concentration should be much higher here rather than in the main recirculating water loop.

This is the approach used at mercury cell caustic chlorine plants for removing any traces (i.e., ppt) of mercury from plant waste water and the food-grade product caustic soda. The water is treated with a ppm concentration or lower of S⁻ ions, and the precipitated mercuric sulphide is filtered out. Residual concentrations of mercury in the food grade caustic soda are removed in the same manner, down to non-detectable limits.

Summarized Advantages of OLGA

The principal advantage of OLGA is that it offers a reliable and sensible solution for the tar problem. The advantages can be summarised as follows:

- Minimal tar related problems
 - Increased system stability and availability
 - Minimization of waste water treatment costs
 - No tar waste streams
- Better gas quality compared to a thermal tar cracker
- More reliable and less vulnerable than a catalytic tar cracker
- No waste water impacts as with tar removal in an aqueous scrubber



Appendix A: Tar Classification system

According to the ECN definition, tar comprises all organic components having a molecular weight higher than benzene. Benzene is not considered to be a tar. ECN uses a tar classification system comprising six classes (see Table B.1). This classification system is in particular developed to provide 'easy' insight in the general composition of tar. Trends are easier recognised on the basis of these classes. However, for more specific problems or issues the detailed data will remain necessary.

Class	Type	Examples
1	GC undetectable tars.	Biomass fragments, heaviest tars (pitch)
2	Heterocyclic compounds. These are components that generally exhibit high water solubility.	Phenol, cresol, quinoline, pyridine
3	Aromatic components. Light hydrocarbons, which are important from the point view of tar reaction pathways, but not in particular towards condensation and solubility.	Toluene, xylenes, ethylbenzene (excluding benzene)
4	Light poly aromatic hydrocarbons (2-3 rings PAHs). These components condense at relatively high concentrations and intermediate temperatures.	Naphthalene, indene, biphenyl, anthracene
5	Heavy poly aromatic hydrocarbons (≥ 4 -rings PAHs). These components condense at relatively high temperature at low concentrations.	Fluoranthene, pyrene, crysene
6	GC detectable, not identified compounds.	Unknowns

Table B.1: Tar classification system

From the practical viewpoint, the classification comprises only tar components that can be measured. Classes 2 to 6 are sampled using the solid phase adsorption (SPA) method and measured by gas chromatography (GC). Although class 6 tars are sampled and measured (a peak is found in the chromatogram), it is unknown what the individual components are. In principle components in this class belong to the other classes, but are here lumped to a single concentration representing the 'unknowns'. Class 1 represents the heavy tar fraction (roughly ≥ 7 -ring PAHs). These components cannot be determined by the combination of SPA and GC. The components are measured by weight and thus represent the gravimetric tars.

Appendix B: OLGA vs. other tar removal systems

Tars from biomass product gases can be removed with a thermal tar cracker, a catalytic tar cracker or a physical process. The thermal and catalytic tar cracker are installed directly downstream the gasifier and operate at high temperature. The physical processes like an aqueous scrubber or OLGA are installed downstream a product gas cooler. The inlet temperature of a tar cracker is typically 850°C and of a physical process 400°C.

Thermal tar cracking

A thermal tar cracker heats up the product gas to a temperature of 1200°C. At this temperature the tars are removed almost completely leading to a very low tar concentration (<100 mg/m³) and tar dew point (<10°C). The disadvantage of this application of a thermal cracker is the reduction in efficiency. To increase the temperature of the product gas a part of the product gas is combusted with oxygen. Consequently, the system efficiency (biomass to electricity) is reduced as well as the calorific value of the product gas. The reduction in calorific value makes the application of the product gas from a direct air blown gasifier in a gas engine difficult.

Catalytic tar cracking

A catalytic tar cracker does not heat up the product gas and thus eliminates the disadvantages of a thermal cracker. In theory the tar removal efficiency can be complete. However, soot formation and deactivation of the catalyst is a serious problem to be dealt with, resulting in limitations in the process. At the moment, the tar concentration at the inlet of the cracker should remain below 2 g/m³ and the presence of alkali metals and sulphur should be controlled. Several projects have shown that a catalytic tar cracker can be a vulnerable part of the system. Bad tar removal by e.g. catalyst deactivation directly leads to heavy tar problems downstream. In principle the tar removal efficiency is less compared with a thermal cracker but good enough for the application of the product gas in a gas engine.

Tar removal by aqueous scrubbers

Aqueous tar removal systems cool down the product gas and remove the tars by condensation. In most aqueous systems dust and tars are collected simultaneously. The product gas is cooled down and aerosols of dust and tars are collected with a wet ESP downstream. Some systems use a dry hot gas filter (HGF) upstream for dust removal instead of a wet ESP. The HGF reduces the risk of fouling of the aqueous system with dust. The tar dew point downstream an aqueous system is similar to or higher than the operating temperature of the system. Therefore, the total tar content downstream an aqueous system can exceed 1 g/m³. To avoid tar condensation and fouling of piping the gas should not cool down. In the aqueous scrubber system a tar/water problem is created. Mixing (heavy) tars with water will lead to operational difficulties in the scrubber and huge maintenance costs. The most important disadvantage is formed by waste water handling. Waste water handling is often so expensive that the plants economical feasibility is at stake.

ATTACHMENT 5
REQUESTED EMISSION STANDARDS

TABLE ATTACHMENT 5-1
REQUESTED EMISSIONS

<i>Pollutant</i>	<i>Fuel</i>	<i>Method of Operation^a</i>	<i>Stack Test^b</i> <i>(3-Run Average)</i>		<i>CEMS^c</i> <i>Compliance</i>	<i>Estimated Emissions</i> <i>(Informational purposes only)</i>
			<i>ppmvd @ 15% O₂</i>	<i>lb/hr^d</i>	<i>ppmvd @ 15% O₂</i>	<i>lb/hr^d</i>
NO _x	Product Gas	CT	32.5	--	32.5	18.4
		CT/DB	32.5	--	32.5	19.2
	Natural Gas ^e	CT	25.0	--	25.0	8.8
		CT/DB	--	--	--	--
CO	Product Gas	CT	50.0	--	50.0	17.2
		CT/DB	50.0	--	50.0	21.4
	Natural Gas ^e	CT	--	--	--	12.1
		CT/DB	--	--	--	--
VOC	Product Gas	CT	--	--	--	4.9
		CT/DB	--	--	--	6.5
	Natural Gas ^e	CT	--	--	--	0.4
		CT/DB	--	--	--	--
PM	Product Gas	CT	--	--	--	6.7
		CT/DB	--	--	--	7.2
	Natural Gas ^e	CT	--	--	--	1.0
		CT/DB	--	--	--	--
SO ₂ (lb/MMBtu)	Product Gas	CT	0.06	--	--	8.8
		CT/DB	0.06	--	--	11.3
	Natural Gas ^e	CT	0.06	--	--	8.8
		CT/DB	0.06	--	--	11.3

- a. CT means operation of CT in combined cycle mode without use of the DB. CT & DB means operation in combined cycle mode and using the DB.
- b. The initial and annual U.S. EPA Reference Method tests associated with the certification of the NO_x and CO CEMS instruments may also be used to demonstrate compliance with the individual standards for product gas and natural gas. Compliance with the NO_x standards will be demonstrated by conducting tests in accordance with EPA Method 7E. Compliance with the CO standards will be demonstrated by conducting tests in accordance with EPA Method 10.
- c. CEMS for NO_x and CO will be installed on the HRSG stacks. Correction to 15% O₂ is required for NO_x, consistent with the provisions of 40 CFR 60, Subpart KKKK. Compliance with the continuous NO_x and CO standards will be demonstrated based on data collected by the required CEMS. NO_x compliance will be based on a 4- hour rolling average for natural gas firing and a 30-day rolling average for product gas firing. CO compliance will be based on a 30-day rolling average. Compliance will be based on all periods, except startup, shutdown, fuel switching or documented malfunction. The CTs will operate above 80% load, or the lowest load at which compliance is demonstrated during initial testing.
- d. The mass emission rate estimates are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.
- e. Limits for natural gas firing are imposed for NO_x and SO₂ only, as required by the New Source Performance Standards pursuant to 40 CFR 60, Subpart KKKK. The natural gas fired values provided for other pollutants are for informational purposes only.

ATTACHMENT 6

SO₂ EMISSION ESTIMATES FROM PRODUCT GAS FIRING

Table Attachment 6-1

Product Gas Firing (CT Only, HI = 147 MMBtu/hr) SO2		
Based on 5ppm H2S concentration		
Conc.	5 ppm	
stack flow rate	403,569 lb/hr	@ 364 deg. F
Heating Value of prod	435 btu/cf	
Temperature	823.67 deg. R	
Heat Input	1.47E+08 Btu/hr	
Volumetric flowrate	##### acfm	@ 364 deg. F
		Assumed MW gas 28.4
SO2	4.55 lb/hr	
	0.03 lb/MMBtu	
$\text{lb/hr} = (\text{ppm}/10^6) \times 2,116.8 \times (60 \times V) \times (\text{MW}/1545.6) \times (1/T)$		
ppm =	parts per million by volume	
V =	volumetric flowrate in acfm or dscfm	
MW =	molecular wt = 64	SO2
T =	temperature of gas in R= F +459.67	
Product Gas Firing (CT/DB, HI= 189 MMBtu/hr) SO2		
Based on 5ppm H2S concentration		
Conc.	5 ppm	
stack flow rate	410,210 lb/hr	@ 364 deg. F
Heating Value of prod	435 btu/cf	
Temperature	823.67 deg. R	
Heat Input	1.89E+08 Btu/hr	
Volumetric flowrate	##### acfm	@ 364 deg. F
		Assumed MW gas 28.4
SO2	4.62 lb/hr	
	0.02 lb/MMBtu	
$\text{lb/hr} = (\text{ppm}/10^6) \times 2,116.8 \times (60 \times V) \times (\text{MW}/1545.6) \times (1/T)$		
ppm =	parts per million by volume	
V =	volumetric flowrate in acfm or dscfm	
MW =	molecular wt = 64	SO2
T =	temperature of gas in R= F +459.67	